CANADIAN NATURAL RESOURCES LIMITED

Q2
Six months ended June 30, 2002

CANADIAN NATURAL ANNOUNCES SEVENTH CONSECUTIVE QUARTER OF INCREASED NATURAL GAS PRODUCTION AND CONTINUED STRONG CASH FLOW AND NET EARNINGS

In commenting on second quarter 2002 results, Canadian Natural's Chairman, Allan Markin, stated "Over the last two years one of our major objectives was to balance our production mix and we are pleased to tell you that this has been accomplished. In fact, the second quarter of 2002 was our seventh consecutive quarter of natural gas production growth. Furthermore, as a result of our recent acquisition of Rio Alto Exploration Ltd. ("Rio Alto"), we now have a new core area for natural gas growth. We are very excited at the prospects and multi-zone potential of this new core area in Northwest Alberta."

"Our asset base is strong with excellent development prospects in natural gas, heavy oil, Pelican Lake oil, International light oil and our world class Horizon Oil Sands Project. With current production balanced at approximately 1.5 billion cubic feet of natural gas per day and 205 thousand barrels of oil per day we will continue to achieve strong levels of cash flow."

"During the quarter, we achieved another milestone on the Horizon Oil Sands Project with the filing of regulatory submissions with the Alberta government. What makes this project so attractive is the ability to produce 230 thousand barrels per day of light synthetic crude oil for more than 50 years, with no production declines. This asset nicely complements our conventional petroleum asset portfolio and adds substantial shareholder value."

"With respect to the Rio Alto acquisition, the assets and team were fully integrated with our own only days after the closing of the acquisition, and the integration is going as well or even better than originally expected. Further, we would like to welcome the Rio Alto staff who have joined our team. We believe that the quality of our people and their belief in our mission statement is what makes our team so strong."

HIGHLIGHTS OF THE SECOND QUARTER

- Natural gas sales volumes of 1,078 million cubic feet per day, an increase of 22% from the second quarter of last year and a 25 million cubic feet per day increase from the previous quarter. This represents the seventh consecutive quarter of natural gas production growth.

- Oil and liquids sales volumes of 189 thousand barrels per day. Production of primary heavy oil and thermal heavy oil accounted for 24% of production on a barrel of oil equivalent basis, similar to the previous quarter.

- Cash flow of $475 million ($3.86 per common share) compared with $528 million ($4.36 per common share) in the second quarter of 2001 and $359 million ($2.95 per common share) in the previous quarter.

- Net earnings of $145 million ($1.18 per common share) compared with $286 million ($2.37 per common share) for the second quarter of 2001 and $99 million ($0.81 per common share) in the previous quarter.

- As a result of lower price differentials for heavy oil production, the Company realized a 12% increase in the wellhead price for its oil and liquids sales over the corresponding quarter of 2001.

- Filed for regulatory approval to construct, operate and reclaim the proposed Horizon Oil Sands Project, located 80 kilometers north of Fort McMurray in Northeastern Alberta, which is expected to produce approximately 230 thousand barrels per day of light synthetic crude oil.

- Successfully completed the $2.3 billion acquisition of Rio Alto with closing effective July 1, 2002. This acquisition increases the Company's current natural gas production to approximately 1.5 billion cubic feet per day, resulting in one of North America's largest natural gas producers.

- Drilled three Slave Point natural gas exploration wells in Northeast British Columbia resulting in one successful well currently producing at 30 million cubic feet per day.

- Offshore Côte d'Ivoire, one additional producing well was brought on-stream at the Espoir field during the quarter with two more anticipated during the third quarter of 2002. Commercial development plans continued on the Baobab field and one additional exploration block was signed up with Canadian Natural owning a 90% working interest and operating the lease.

- Successfully continued the experimental Pelican Lake emulsion flood injection pilot, which has the potential to significantly increase the recoverable oil in the pool. Canadian Natural operated lands in this area are 100% owned and contain approximately 80% of the pool.

OPERATIONS REVIEW

Production

The quarterly results show the strength of the Company's business approach to diversification among commodities produced, namely natural gas, light oil, Pelican Lake oil, primary heavy oil and thermal heavy oil.

Second quarter 2002 natural gas production averaged 1,078 million cubic feet per day, an increase of 22% from the second quarter of 2001 and a 25 million cubic feet per day increase from the first quarter of 2002. Second quarter production included the benefit of the commissioning, in early March, of the Canadian Natural operated pipeline that connected the Ladyfern area to sales facilities in Alberta, and increased field take-away capacity. Natural gas production accounted for 49% of the Company's production this quarter.

Production of oil and liquids in the second quarter of 2002 was lower than the previous quarter and the second quarter of last year, largely the result of decreases in North Sea production, the shut-down of the Kiame field in Angola, and the proactive management of heavy oil supply and drilling activity. Decreases in North Sea production were primarily due to the effect of a first quarter property exchange, the implementation of reservoir management techniques designed to enhance the ultimate recovery factor from the Banff field and pipeline downtime at the Kyle field. During the second quarter, a blockage in the Kyle export natural gas pipeline resulted in restricted oil production in order to satisfy natural gas flaring restrictions that remained in effect. This blockage was repaired in early July and production levels have increased accordingly.

Light oil and Pelican Lake oil production together account for 27% of the Company's total equivalent production. Light oil production reflected lower North Sea output and the shut-down of the Kiame field partially offset by increased production in Canada due to minor acquisitions and at the Espoir field in Côte d'Ivoire, where one new producing well was brought on production in May. Recent increases in conventional heavy oil drilling are expected to lead to production increases in future quarters.

The Company's production composition is as follows:

	Q2 2002		Q1 2002		Q2 2001	
	mboe/d	*%*	*mboe/d*	*%*	*mboe/d*	*%*
Natural gas	**179.6**	**49**	175.6	48	147.5	41
Light oil and NGLs	**70.1**	**19**	72.2	20	80.6	22
Pelican Lake oil	**30.8**	**8**	26.6	7	34.1	10
Primary heavy oil	**51.3**	**14**	48.0	13	58.8	16
Thermal heavy oil	**37.2**	**10**	41.6	12	41.2	11
	369.0	**100**	364.0	100	362.2	100

The Company expects production levels in 2002 to average 1,290 to 1,340 million cubic feet per day of natural gas (2001 – 918 mmcf/day) and 205 to 215 thousand barrels per day of oil and liquids (2001 – 206 mbbls/day).

DRILLING ACTIVITY *(number of wells)*

	SIX MONTHS ENDED JUNE 30			
	2002		2001	
	Gross	Net	Gross	Net
Oil	**223**	**193**	202	182
Natural gas	**136**	**123**	340	287
Dry	**24**	**20**	28	25
Subtotal	**383**	**336**	570	494
Injection/strat tests	**415**	**407**	251	249
Total	**798**	**743**	821	743
Success rate *(excluding injection/strat tests)*		**94%**		95%

Canadian Natural drilled 146 net oil wells and 28 net natural gas wells during the second quarter of 2002. These wells were concentrated in the Company's heavy oil areas of North Alberta/West Saskatchewan, the light oil area of Southeast Saskatchewan and its three natural gas core areas. The total success rate for Canadian Natural's drilling program was 96% during the second quarter, excluding injection/stratigraphic test wells.

The number of wells drilled during the first half of the year (excluding injection/stratigraphic test wells) decreased 32% from the prior year, comprised of a 57% reduction in natural gas well drilling and a 6% increase in oil well drilling. The decrease in natural gas drilling reflects the Company's strategy of building an inventory of natural gas locations to offset future Ladyfern production declines and reflects its capital allocation policy which opportunistically has shifted additional capital into heavy oil drilling to take advantage of favorable market pricing.

During the first six months of the year, the Company drilled 404 stratigraphic test wells on the oil sands leases in the Horizon Oil Sands Project and in North Alberta/West Saskatchewan.

Pricing

Netbacks received for Canadian Natural's heavy oil and Pelican Lake oil production improved significantly over the last year due to the narrowing of price differentials to WTI in the first half of the year. Indications are that this will continue into the third quarter as seasonal demand increases and a heavy oil refinery in the US midwest reaches full capacity following a major fire in late August of last year.

A comparison of the price received for the Company's North American production is as follows:

	Pricing Indications as at Aug 5, 2002	Q2/02	Q1/02	Q2/01
WTI benchmark price *(US $/bbl)*	**$ 26.58**	**$ 26.26**	$ 21.67	$ 27.96
Differential to LLB blend *(US $/bbl)*	**$ 4.07**	**$ 6.04**	$ 5.73	$ 11.70
Condensate benchmark price *(US $/bbl)*	**$ 26.61**	**$ 26.36**	$ 20.83	$ 33.04
NYMEX benchmark price *(US $/mmbtu)*	**$ 2.68**	**$ 3.37**	$ 2.40	$ 4.78
AECO benchmark price *(Cdn $/mmbtu)*	**$ 2.79**	**$ 4.43**	$ 3.35	$ 7.08
Canadian Natural's Wellhead Price[1]				
Light oil and NGLs *(Cdn $/bbl)*	**$ 33.59**	**$ 31.90**	$ 27.83	$ 36.03
Pelican Lake oil *(Cdn $/bbl)*	**$ 32.75**	**$ 25.05**	$ 21.89	$ 18.80
Primary heavy oil *(Cdn $/bbl)*	**$ 32.72**	**$ 24.54**	$ 20.54	$ 16.74
Thermal heavy oil *(Cdn $/bbl)*	**$ 31.48**	**$ 23.73**	$ 19.40	$ 14.53
Natural gas *(Cdn $/mcf)*	**$ 2.60**	**$ 3.72**	$ 3.05	$ 5.99

(1) *Including financial instruments.*

The Company believes that current natural gas prices are below levels necessary to sustain the industry over the long-term. This commodity price should increase to more economic levels as current North American storage levels return to normal, lower industry-wide North American natural gas drilling reduces supplies and normal weather patterns return. Furthermore, the Company believes that current price differentials between Alberta AECO pricing and US NYMEX pricing are short-term anomalies resulting from maintenance downtime on common carrier pipeline systems. The Company's natural gas price continues to be affected by the amount of natural gas sold through its British Columbia facilities which have received a lower price this year and the higher cost of owning our own sales pipeline space.

ACTIVITY BY CORE REGION

	Net Undeveloped Land As at June 30, 2002 *(thousands of net acres)*	Drilling Activity Period ended June 30, 2002 *(net wells)*
Northeast British Columbia/Northwest Alberta	**1,510**	**43**
North Alberta/West Saskatchewan	**3,722**	**391**
Horizon Oil Sands	**239**	**256**
South Alberta	**677**	**46**
Southeast Saskatchewan	**150**	**3**
United Kingdom North Sea	**292**	**1**
Offshore West Africa	**1,252**	**3**

North America Conventional

At the Ladyfern field, Canadian Natural produced 201 million cubic feet per day during the second quarter compared with 165 million cubic feet per day of natural gas last quarter. July production levels are at approximately 200-210 million cubic feet per day. As a result of 2002's strong Ladyfern production increases, Canadian Natural has reduced current year natural gas drilling activity with a view to building prospect inventories in anticipation of expected high Ladyfern declines. Additionally, the Company has an ongoing high impact natural gas exploration program in Northeast British Columbia through 2002.

During the quarter, the Company was successful on one of its three Slave Point exploration wells. The C-18-H well in Northeast British Columbia, 100% owned by Canadian Natural, has been tied in to company owned pipeline facilities and is currently producing at 30 million cubic feet per day.

Canadian Natural plans to continue its exploration program in deeper formations in Northeast British Columbia, including the Slave Point trend, where one additional well will be drilled in fall 2002 and additional wells will be drilled during the winter of 2002/03. The Slave Point horizon is technically complex making it a high-risk exploration target. Canadian Natural exploration activities benefit from owning the area's largest database of 2-D and 3-D seismic information and from its extensive landholdings in the region.

The experimental Pelican Lake emulsion flood continued to meet expectations during the second quarter, with injections continuing since early April 2002. If successful, this project will substantially increase the recovery factor from the thin Pelican Lake sands. This field contains approximately three billion barrels of original oil-in-place but is only expected to achieve a 6% recovery factor using primary technologies. Based upon positive laboratory testing, this project could double or triple recovery factors if the technology can be implemented in the field. Data will continue to be gathered on the success of this test throughout the last half of 2002.

North America Horizon Oil Sands Project

Regulatory submissions, including an Environmental Impact Assessment and Project Description, were completed and filed on June 28, 2002 with approvals expected during the next 12-18 months.

The proposed project will provide for a potential recovery of nearly six billion barrels of bitumen over an estimated 50-year life span. The project will involve three major components: surface mining and bitumen extraction, an upgrader and associated infrastructure. Construction is estimated to start in 2004, once necessary regulatory approvals are received and detailed engineering is approximately 80% completed. Commissioning and start-up is expected in late 2007 at 110 thousand barrels per day of light synthetic crude oil, with full production capacity of 232 thousand barrels per day by 2011. Opportunities for up to an additional 70 thousand barrels per day of in-situ bitumen recoveries are also possible from this lease.

During the second quarter, the Company continued second phase project engineering, which included selection of and awarding of contracts to various engineering firms for each of extraction, utility and offsite, primary upgrading, secondary upgrading and upgrading support units. Licensing of the delay coking process and the hydroprocessing unit were also completed. Prequalification of potential contractors for design and construction of access roads was also accomplished.

United Kingdom

During the second quarter, Kyle field production was reduced to 2,380 barrels of oil equivalent per day due to a blockage in the Kyle export natural gas pipeline which resulted in restricted oil production in order to satisfy natural gas flaring restrictions that remained in effect. This production issue was rectified in July 2002. One additional well was drilled at the Kyle field during the second quarter and is now tied in and producing. Also during the second quarter, production at the Banff field was reduced in a proactive effort to maximize ultimate field recoveries and economics.

During the quarter, Canadian Natural completed a property swap that increased its ownership in the Ninian field and received cash in exchange for a minor non-operated interest in the Claymore field.

Offshore West Africa

During the quarter, Canadian Natural continued the development of the 59% owned and operated Espoir field located offshore Côte d'Ivoire with the drilling of two additional production wells. One of these wells was completed and tied in during May with the second coming on-stream during July. Additional producing wells are to be drilled in August and October 2002. Production from Espoir wells is tied in to the floating production, storage and offtake vessel ("FPSO"), the "Espoir Ivoirien", which commenced operations in February 2002.

Evaluation work also continues on the Baobab discovery where drilling results, combined with additional geophysical and geological modelling, has resulted in Canadian Natural increasing its reserve estimates on the Baobab field close to one billion barrels of oil in place, with 200 million barrels being potentially recoverable. This field is now large enough to warrant stand alone development, and Canadian Natural is proceeding with development plans. While determination of optimum facilities size continues, it is anticipated that production in the range of 50-65 thousand barrels of oil per day to a new FPSO could commence in late 2004. Field development plans have been submitted to the Government with finalization expected in the last quarter of this year.

Canadian Natural has also acquired an interest in exploration Block CI-400 in deeper waters offshore Côte d'Ivoire. This block is located adjacent to the Baobab discovery. Block CI-400 comprises 176,075 acres and is located approximately 16 kilometers offshore in water depth ranging from 150 meters to 2,300 meters. Canadian Natural will operate Block CI-400 and retain a 90% working interest.

Production from the Kiame field, offshore Angola, ceased in April 2002. This field was acquired as part of the Ranger Oil acquisition during 2000 and at that time, it was expected that production would likely become uneconomic in 2001. Also in Angola, Canadian Natural honored a commitment through participation with a 25% interest in the Mariposa well located in offshore Block 19, which was dry and abandoned. Canadian Natural has also decided to exit from its position in the Aje field, located offshore Nigeria. Since its appointment as technical advisor in late 2001, Canadian Natural has completed extensive rework of seismic data and has determined that to continue the project would result in further expenditures which do not meet the Company's economic thresholds.

FINANCIAL REVIEW

Canadian Natural recognizes the need for a strong financial position in order to withstand volatile oil and natural gas commodity prices and the operational risks inherent in the oil and natural gas business environment.

Long-term debt at June 30, 2002 amounted to $2.4 billion and reflected a 1.5x debt to cash flow ratio and a debt to book capitalization of 37.4%. Following completion of the Rio Alto acquisition on July 1, 2002, long-term debt amounted to $4.2 billion and reflected a 2.2x debt to pro forma cash flow ratio and a debt to book capitalization of 47.8%.

Canadian Natural has used its balance sheet to complete opportunistic acquisitions on three prior occasions and in each of those cases, the balance sheet was proactively managed to targeted levels. The Rio Alto acquisition will be no different.

Canadian Natural maintains shelf prospectuses for the separate offering of medium term notes in Canada and debt securities in the United States. The securities, if and when issued, will be unsecured and will rank pari passu with other senior unsecured indebtedness of Canadian Natural. Debt ratings, following announcement of the Rio Alto acquisition were reaffirmed as "Baa1" by Moody's Investors Service, Inc., "BBB+" by Standard & Poor's Corporation and "BBB (high)" by Dominion Bond Rating Service Limited. Future offerings under the shelf prospectuses will provide flexibility to the Company's debt investment base, extend maturities and provide balance in fixed/floating interest rate ratios.

In response to the expected demand for oil and natural gas, the related pricing and to protect capital expenditure programs, the Company has entered into several financial instruments to manage exposure to market volatility. The details of these positions are set out in note 6 to the consolidated financial statements. The Company will continue to actively pursue additional hedging opportunities.

The regular third quarter dividend payment will occur on October 1, 2002 and will be made to shareholders of record at the close of business on September 13, 2002.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis ("MD&A") of the financial condition and results of operations should be read in conjunction with the unaudited interim consolidated financial statements for the six months ended June 30, 2002 and the MD&A and the audited consolidated financial statements for the year ended December 31, 2001.

Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

ACQUISITION OF RIO ALTO EXPLORATION LTD.

Effective July 1, 2002, the Company paid cash of $850.0 million and issued 10,008,000 common shares with an attributed value of $522.4 million to acquire all of the issued and outstanding common shares of Rio Alto Exploration Ltd. ("Rio Alto") by way of a plan of arrangement. The results of Rio Alto will be consolidated with the results of the Company commencing July 1, 2002, and are not reflected in the results of the Company for the six months ended June 30, 2002. The pro forma consolidated financial statements at June 30, 2002 are included in Appendix A to the second quarter 2002 report.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001[1]**	**JUNE 30 2002**	**JUNE 30 2001[1]**
FINANCIAL HIGHLIGHTS *($ millions, except per share amounts)*					
Revenue	**$ 863**	$ 718	$ 981	**$ 1,581**	$ 2,112
Cash flow from operations attributable to common shareholders[2]	**$ 475**	$ 359	$ 528	**$ 834**	$ 1,157
Per share – basic	**$ 3.86**	$ 2.95	$ 4.36	**$ 6.82**	$ 9.51
– diluted	**$ 3.70**	$ 2.85	$ 4.17	**$ 6.57**	$ 9.11
Net earnings attributable to common shareholders[3]	**$ 145**	$ 99	$ 286	**$ 244**	$ 508
Per share – basic	**$ 1.18**	$ 0.81	$ 2.37	**$ 2.00**	$ 4.18
– diluted	**$ 1.09**	$ 0.79	$ 2.23	**$ 1.89**	$ 4.02
Capital expenditures, net of dispositions	**$ 305**	$ 459	$ 368	**$ 764**	$ 1,003

(1) *Restated for change in accounting policy (see consolidated financial statement notes 1 and 2).*
(2) *After dividend on preferred securities.*
(3) *After dividend and revaluation of preferred securities.*

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001[1]**	**JUNE 30 2002**	**JUNE 30 2001[1]**
OPERATING HIGHLIGHTS					
Oil and liquids *($/bbl, except daily production)*					
Daily production *(bbls/d)*	**189,386**	188,439	214,716	**188,915**	210,177
Sales price	**$ 28.27**	$ 24.50	$ 25.32	**$ 26.40**	$ 23.73
Royalties	**3.02**	2.28	2.42	**2.65**	2.39
Production expense	**7.95**	7.81	7.57	**7.88**	7.86
Netback	**$ 17.30**	$ 14.41	$ 15.33	**$ 15.87**	$ 13.48
Natural gas *($/mcf, except daily production)*					
Daily production *(mmcf/d)*	**1,078**	1,053	885	**1,066**	868
Sales price	**$ 3.68**	$ 3.06	$ 5.93	**$ 3.38**	$ 7.57
Royalties	**0.77**	0.55	1.47	**0.66**	1.92
Production expense	**0.57**	0.58	0.50	**0.58**	0.50
Netback	**$ 2.34**	$ 1.93	$ 3.96	**$ 2.14**	$ 5.15
Barrels of oil equivalent *($/boe, except daily production)*					
Daily production *(boe/d)*	**369,022**	363,990	362,154	**366,520**	354,809
Sales price	**$ 25.29**	$ 21.58	$ 29.54	**$ 23.46**	$ 32.61
Royalties	**3.79**	2.78	5.03	**3.29**	6.12
Production expense	**5.76**	5.73	5.72	**5.75**	5.89
Netback	**$ 15.74**	$ 13.07	$ 18.79	**$ 14.42**	$ 20.60

[1] *Restated for change in accounting policy (see consolidated financial statement note 1).*

Cash flow and net earnings for the three and six months ended June 30, 2002 decreased from the comparable periods in 2001 due to lower natural gas prices and decreased oil and liquids production. Cash flow and net earnings increased in the second quarter compared to the first quarter of 2002 due to increased production of natural gas and higher product prices. Net earnings in the second quarter also increased due to the strengthening Canadian dollar, resulting in unrealized foreign exchange gains on the Company's US dollar denominated debt. These increases were partially offset by the write off of certain international properties.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001**	**JUNE 30 2002**	**JUNE 30 2001**
DAILY PRODUCTION					
Oil and liquids *(bbls/d)*					
North America	**158,196**	152,268	168,938	**155,248**	172,500
North Sea	**25,685**	30,910	41,556	**28,283**	34,422
Offshore West Africa	**5,505**	5,261	4,222	**5,384**	3,255
Total	**189,386**	188,439	214,716	**188,915**	210,177
Natural gas *(mmcf/d)*					
North America	**1,058**	1,026	873	**1,042**	862
North Sea	**20**	27	12	**24**	6
Total	**1,078**	1,053	885	**1,066**	868
Product mix					
Light oil and NGLs	**19.0%**	19.9%	22.3%	**19.4%**	20.5%
Pelican Lake oil	**8.3%**	7.3%	9.4%	**7.8%**	10.4%
Primary heavy oil	**13.9%**	13.2%	16.2%	**13.6%**	16.3%
Thermal heavy oil	**10.1%**	11.4%	11.4%	**10.7%**	12.0%
Natural gas	**48.7%**	48.2%	40.7%	**48.5%**	40.8%

Oil and liquids production decreased from the comparable periods in 2001 due to the Company’s focus on natural gas development opportunities. When compared to the same period last year, oil and liquids production decreased due to the curtailment of 15,000 bbls/day of its North American heavy oil production in December 2001 and early 2002. Oil and liquids production also decreased due to the substantial reduction in the number of primary heavy oil wells that were drilled in the first quarter of 2002, as well as the extension of Primrose steam cycles and the resulting delay in associated oil recovery cycles. Oil and liquids production from the North Sea decreased from the previous quarter because operations at Kyle were impacted by a blockage in the export natural gas pipeline downstream of the Curlew floating production, storage and offtake vessel. As a result of this blockage, oil production from Kyle was restricted for most of the quarter in order to satisfy natural gas flaring restrictions that remained in effect. The pipeline blockage was rectified and production recommenced in early July. In addition, oil and liquids production was reduced in the North Sea due to the implementation of reservoir management techniques designed to enhance the ultimate recovery factor from the Banff and Kyle fields and as a result of property exchanges occurring in the first quarter of 2002. Offshore West Africa oil and liquids production increased from the comparable periods in 2001 as a result of production commencing from the Company’s operated Espoir field, located offshore Côte d’Ivoire, in February 2002. The second producer well came on production in mid-May 2002 and a third producer well was completed in early July. Production from this field is anticipated to increase over the next several months as additional wells are drilled during the first phase of development. As planned, production from the Kiame field in Angola ceased in April 2002.

Natural gas production increased from the comparable periods in 2001 as a result of the focus of the 2001 capital expenditure program on natural gas development, which resulted in the development of the Ladyfern field. Production from the Ladyfern field increased over the prior periods due to the commissioning of the Ladyfern sales pipeline in March 2002, which increased take-away capacity. Natural gas production in the North Sea decreased from the previous quarter due to the curtailment of production from the Kyle field as a result of the pipeline blockage.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001**	**JUNE 30 2002**	**JUNE 30 2001**
PRODUCT PRICES					
Oil and liquids *($/bbl)*					
North America	**$ 26.27**	$ 22.18	$ 20.59	**$ 24.27**	$ 19.72
North Sea	**$ 39.36**	$ 33.75	$ 43.07	**$ 36.31**	$ 42.27
Offshore West Africa	**$ 33.92**	$ 37.61	$ 39.75	**$ 35.71**	$ 40.04
Company average	**$ 28.27**	$ 24.50	$ 25.32	**$ 26.40**	$ 23.73
Natural gas *($/mcf)*					
North America	**$ 3.72**	$ 3.05	$ 5.99	**$ 3.39**	$ 7.61
North Sea	**$ 1.80**	$ 3.77	$ 1.74	**$ 2.92**	$ 1.74
Company average	**$ 3.68**	$ 3.06	$ 5.93	**$ 3.38**	$ 7.57
Percentage of revenue					
Oil and liquids	**57.5%**	58.9%	51.0%	**58.1%**	43.2%
Natural gas	**42.5%**	41.1%	49.0%	**41.9%**	56.8%

The North American realized oil and liquids price increased from the comparable periods in 2001 due to lower heavy oil differentials. Heavy oil differentials averaged US $5.89 per bbl in the first half of 2002 compared to US $12.34 per bbl in the first half of 2001 due to supply and demand fundamentals as well as the recommencement of a heavy oil refinery in the U.S. Midwest. North Sea oil and liquids prices decreased from the comparable periods due to lower WTI prices. Product pricing has increased from March 31, 2002 due to higher worldwide prices.

Natural gas prices decreased from the comparable periods in 2001 due to lower demand in the North American market and warmer than average winter temperatures, which resulted in higher natural gas storage levels. Natural gas prices increased from the prior quarter due to an improvement in the economic outlook. The Company expects natural gas prices to increase due to the impact that reduced drilling levels will have on supply and as North American storage levels and weather patterns return to normal. Natural gas prices have also been impacted by the recent restrictions on export capacity out of Alberta due to temporary anomalies resulting from maintenance downtime on common carrier pipeline systems.

Financial instruments are entered into by the Company to protect the downside prices received on the sale of a portion of its oil and natural gas production. The price realized from the sale of oil was reduced by $1.85 per bbl in the quarter ended June 30, 2002 ($0.50 per bbl and $0.43 per bbl reduction, respectively, in the quarters ended March 31, 2002 and June 30, 2001). The price realized from the sale of natural gas was decreased by $0.09 per mcf in the second quarter of 2002 ($0.08 per mcf increase and $0.31 per mcf reduction, respectively, in the quarters ended March 31, 2002 and June 30, 2001).

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001**	**JUNE 30 2002**	**JUNE 30 2001**
ROYALTIES					
Oil and liquids *($/bbl)*					
North America	**$ 3.29**	$ 2.46	$ 2.51	**$ 2.88**	$ 2.40
North Sea	**$ 1.76**	$ 1.54	$ 2.23	**$ 1.64**	$ 2.48
Offshore West Africa	**$ 1.11**	$ 1.65	$ 0.65	**$ 1.37**	$ 0.43
Company average	**$ 3.02**	$ 2.28	$ 2.42	**$ 2.65**	$ 2.39
Natural gas *($/mcf)*					
North America	**$ 0.79**	$ 0.57	$ 1.49	**$ 0.67**	$ 1.93
Company average	**$ 0.77**	$ 0.55	$ 1.47	**$ 0.66**	$ 1.92
Company average *($/boe)*	**$ 3.79**	$ 2.78	$ 5.03	**$ 3.29**	$ 6.12
Percentage of revenue *(excluding financial instruments)*					
Oil and liquids	**10.0%**	9.1%	9.4%	**9.6%**	10.0%
Natural gas	**20.4%**	18.5%	23.6%	**19.6%**	23.7%

Oil and liquids royalties in North America increased over the comparable periods in 2001 due to higher product prices. North America oil and liquids royalties have also increased due to some heavy oil projects reaching payout and no longer qualifying for reduced royalty rates. North Sea oil and liquids royalties decreased from the comparable periods in 2001 due to lower world oil prices, but increased from the first quarter 2002 due to decreased production from the non-royalty paying Kyle field. Offshore West Africa royalties increased from the comparable periods in 2001 due to the Kiame field reaching payout in June 2001. The Kiame field was the only field on production in 2001 in this segment. Oil and liquids royalties decreased in the second quarter of 2002 compared to the first quarter 2002 as a result of production ceasing from the higher royalty rate Kiame field in April.

North American natural gas royalties have changed from the comparable periods as a result of fluctuations in the sales price of natural gas.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001[1]**	**JUNE 30 2002**	**JUNE 30 2001[1]**
PRODUCTION EXPENSE					
Oil and liquids *($/bbl)*					
North America	**$ 6.52**	$ 6.97	$ 7.11	**$ 6.74**	$ 7.38
North Sea	**$ 15.72**	$ 10.09	$ 8.42	**$ 12.66**	$ 8.73
Offshore West Africa	**$ 12.76**	$ 18.62	$ 17.23	**$ 15.61**	$ 24.73
Company average	**$ 7.95**	$ 7.81	$ 7.57	**$ 7.88**	$ 7.86
Natural gas *($/mcf)*					
North America	**$ 0.55**	$ 0.56	$ 0.50	**$ 0.56**	$ 0.50
North Sea	**$ 1.90**	$ 1.33	$ 0.61	**$ 1.57**	$ 0.61
Company average	**$ 0.57**	$ 0.58	$ 0.50	**$ 0.58**	$ 0.50
Company average *($/boe)*	**$ 5.76**	$ 5.73	$ 5.72	**$ 5.75**	$ 5.89

[1] *Restated for change in accounting policy (see consolidated financial statement note 1).*

North American oil and liquids production expense decreased from the comparable periods in 2001 due to lower costs of natural gas, which is used to produce the steam to heat thermal heavy oil formations. Oil and liquids production expense decreased in North America from the prior quarter due to the allocation of fixed costs over greater production volumes. North Sea oil and liquids production expense increased over the comparable periods due to a combination of costs associated with the natural gas pipeline blockage and decreased oil production in 2002. Offshore West Africa oil and liquids production expense decreased from the comparable periods due to production ceasing from the higher production cost Kiame field and increased production from the Espoir field. Costs are expected to decline on a per barrel basis as production from the Espoir field increases.

Natural gas production expense increased over the comparable periods in 2001 due to an increase in the toll rates and the percentage of natural gas produced through the gathering and processing system in British Columbia. Natural gas production expense is expected to decrease as a result of the commissioning of the Ladyfern sales pipeline and the expiry of the Ladyfern McMahon service fee at the end of June 2002.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	**MARCH 31 2002**	**JUNE 30 2001**	**JUNE 30 2002**	**JUNE 30 2001**
DEPLETION, DEPRECIATION AND AMORTIZATION[1]					
Expense *($ millions)*	**$ 289.3**	$ 232.0	$ 216.3	**$ 521.3**	$ 423.5
$/boe	**$ 8.61**	$ 7.08	$ 6.56	**$ 7.86**	$ 6.59

[1] *DD&A does not include midstream operations.*

Depletion, depreciation and amortization ("DD&A") increased from the prior quarter and the comparable periods in 2001 due to higher finding and development costs associated with natural gas exploration. In Angola, following a technical review of the results of the Mariposa well where the Company held a 25% non-operated working interest, the Company is now pursuing an exit strategy from Block 19. All costs associated with Block 19, amounting to $37 million, have been written off. In addition, the revised depth structure of the Aje field in Nigeria showed the structural closure was greatly reduced. The reduction in likely oil-in-place and associated increase in risk means that the project fails to meet the Company's economic threshold. The Company has therefore decided to withdraw from its only interest in Nigeria and costs totalling $14 million have been written off.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	MARCH 31 2002	JUNE 30 2001	JUNE 30 2002	JUNE 30 2001
ADMINISTRATION EXPENSE					
Net expense *($ millions)*	**$ 12.3**	$ 13.5	$ 7.9	**$ 25.8**	$ 16.2
$/boe	**$ 0.37**	$ 0.41	$ 0.24	**$ 0.39**	$ 0.25

The Company's administration expense increased from comparable periods in 2001 due to higher overall costs including compensation costs associated with increased staffing levels and lower capital recoveries on reduced well drilling and associated capital spending.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	MARCH 31 2002	JUNE 30 2001	JUNE 30 2002	JUNE 30 2001
INTEREST EXPENSE					
Interest expense *($ millions)*	**$ 28.6**	$ 28.7	$ 34.8	**$ 57.3**	$ 74.2
$/boe	**$ 0.85**	$ 0.88	$ 1.05	**$ 0.86**	$ 1.16
Average effective interest rate	**4.36%**	4.12%	5.63%	**4.24%**	5.94%

Interest expense decreased from the comparable periods in the prior year due to a lower average effective interest rate.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	MARCH 31 2002	JUNE 30 2001	JUNE 30 2002	JUNE 30 2001
MIDSTREAM *($ millions)*					
Revenue	**$ 13.5**	$ 10.4	$ 7.7	**$ 23.9**	$ 17.5
Operating costs	**3.4**	3.1	2.9	**6.5**	7.0
Cash flow	**10.1**	7.3	4.8	**17.4**	10.5
Depreciation	**1.9**	1.9	0.8	**3.8**	1.7
Segment earnings before taxes	**$ 8.2**	$ 5.4	$ 4.0	**$ 13.6**	$ 8.8

The Company's midstream assets consist of the 100% owned and operated ECHO pipeline, the 15% interest in the Cold Lake pipeline system, the 62% interest in the operated Pelican Lake pipeline and the 50% interest in the 80 megawatt co-generation system located in the Primrose area. The midstream pipeline assets allow the Company to transport its own production volumes as well as earn third party revenue from excess capacity. Through these assets, the Company transports in excess of 75% of its heavy oil to the international mainline liquid pipelines. These midstream assets enhance the Company's ability to control the full range of costs associated with the development and marketing of its heavy oil.

Revenue from midstream assets increased from the comparable periods in 2001 due to the expansion of the ECHO pipeline and the commencement of operations from the Cold Lake pipeline system in late December 2001. The increased pipeline revenues offset the decline in electricity revenue. Electricity revenues declined over the same period in 2001 due to lower prices received. Revenue from midstream assets increased in the second quarter of 2002 from the first quarter due to increased revenue from the Pelican Lake and Cold Lake pipeline systems.

	THREE MONTHS ENDED						SIX MONTHS ENDED			
		JUNE 30 2002		**MARCH 31 2002**		**JUNE 30 2001**		**JUNE 30 2002**		**JUNE 30 2001**
TAXES										
Taxes other than income tax *($ millions)*										
Current	**$**	**11.8**	$	13.5	$	21.0	**$**	**25.3**	$	38.1
Deferred		**1.6**		1.4		(0.7)		**3.0**		0.1
Total	**$**	**13.4**	$	14.9	$	20.3	**$**	**28.3**	$	38.2
Current income tax *($ millions)*										
North Sea	**$**	**2.3**	$	11.0	$	25.2	**$**	**13.3**	$	35.0
Offshore West Africa		**1.1**		0.5		-		**1.6**		-
Large Corporations Tax		**4.5**		4.3		3.3		**8.8**		7.2
Total	**$**	**7.9**	$	15.8	$	28.5	**$**	**23.7**	$	42.2
Future income tax *($ millions)*	**$**	**107.9**	$	38.3	$	64.5	**$**	**146.2**	$	219.7
Effective income tax rate		**45.1%**		35.0%		24.4%		**41.3%**		33.7%

Taxes other than income tax consist of current and deferred petroleum revenue tax and other international taxes and provincial resource surcharges. The decrease in taxes other than income tax from comparable periods is due to the decrease in world oil prices, primarily in the North Sea.

The decrease in current income tax expense from the comparable periods in 2001 is due to lower world oil prices and decreased oil and liquids production from the North Sea, resulting in lower taxable income. Current income tax also decreased due to the UK Government increasing the first year capital allowance rate for plant and machinery expenditures to 100% from the previous rate of 25%.

Future income tax expense increased from the prior quarter as a result of increased earnings before taxes, and due to the substantively enacted supplementary charge of 10% on profits from North Sea oil and natural gas production. The supplementary charge is in addition to the current corporate tax rate of 30%. The supplementary charge took effect April 17, 2002 and excludes any deduction for financing costs. The implementation of the supplementary charge resulted in a one-time increase in the UK future income tax liability of $34 million. The increase in future income tax expense was partially offset by a $21 million reduction in the future income tax liability as a result of a decrease in a Canadian province's corporate income tax rate. A similar reduction of $46 million occurred during the second quarter 2001. The Company's future income taxes payable and property, plant and equipment have been decreased by $26 million to provide for the exchange of non-tax base assets in the North Sea in the first half of 2002.

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	MARCH 31 2002	JUNE 30 2001[1]	JUNE 30 2002	JUNE 30 2001[1]
CAPITAL EXPENDITURES *($ millions)*					
Expenditures on property, plant and equipment					
Net property acquisitions	**$ 33.1**	$ 35.3	$ 55.5	**$ 68.4**	$ 246.2
Land acquisition and retention	**19.2**	27.8	21.5	**47.0**	49.2
Seismic evaluations	**14.6**	24.8	20.2	**39.4**	57.2
Well drilling, completion and equipping	**135.9**	206.8	153.0	**342.7**	380.2
Pipeline and production facilities	**66.6**	124.3	105.0	**190.9**	216.4
Total net reserve replacement expenditures	**269.4**	419.0	355.2	**688.4**	949.2
Project Horizon	**16.6**	22.3	4.8	**38.9**	13.9
Midstream	**5.2**	9.6	6.8	**14.8**	35.7
Abandonments	**11.9**	6.8	(0.2)	**18.7**	1.0
Head office	**1.7**	1.1	1.4	**2.8**	2.9
Total net capital expenditures	**$ 304.8**	$ 458.8	$ 368.0	**$ 763.6**	$ 1,002.7
By segment					
North America	**$ 232.5**	$ 420.1	$ 248.6	**$ 652.6**	$ 797.8
North Sea	**13.2**	(31.4)	16.5	**(18.2)**	31.3
Offshore West Africa	**53.9**	60.5	96.1	**114.4**	137.9
Midstream	**5.2**	9.6	6.8	**14.8**	35.7
Total	**$ 304.8**	$ 458.8	$ 368.0	**$ 763.6**	$ 1,002.7

[1] *Certain figures provided for prior periods have been reclassified to conform to the presentation adopted in 2002.*

North America capital expenditures include natural gas exploration that concentrated on larger outlying pools in the Ladyfern area. A total of 8 prospects were drilled in the first half of 2002, resulting in 2 successful wells. The second quarter saw the drilling of 106 heavy oil wells and 33 oil wells on the Pelican Lake properties. The Pelican Lake emulsion flood project began in April 2002. This experimental technique is expected to improve the recovery rate, the effectiveness of which will not be known until late 2002 or early 2003. The second quarter 2002 also saw the filing of an application for regulatory approval to construct, operate, and reclaim the proposed Horizon Oil Sands Project, located about 80 kilometers north of Fort McMurray, in northeastern Alberta's Regional Municipality of Wood Buffalo. Construction of the Horizon Project is expected to start in 2004, with production expected to begin in 2007 at 110,000 bbls/day of light synthetic crude oil.

North Sea capital expenditures for the three months ended June 30, 2002, include the consolidation of interests in the Ninian field. In exchange for an additional 4.25% interest in Ninian and cash, the Company sold its 4.19% interest in the Claymore field. The Company now holds a 28.34% interest in the Ninian field. North Sea capital expenditures also include the drilling of wells at the Kyle and Columba E fields, as well as the ongoing infill drilling program in the Ninian field.

Offshore West Africa capital expenditures include the continued development of the Espoir field. During the second quarter 2002, another producing well and a water injection well were completed. A third producer well was completed in mid-July. During the remainder of 2002, the Company plans to drill two additional producer wells as part of the first development phase. The second quarter 2002 capital expenditures also include the awarding of the 90% owned and operated Block CI-400 in Côte d'Ivoire and the continuing work on the Baobab development plan.

	PRO FORMA JULY 1 2002(1)	JUNE 30 2002	MARCH 31 2002	DEC 31 2001(2)	JUNE 30 2001(2)
LIQUIDITY AND CAPITAL RESOURCES *($ millions, except ratios)*					
Working capital deficit	**$ 220.9**	**$ 128.9**	$ 84.5	$ 5.6	$ 113.9
Long-term debt	**4,172.4**	**2,404.4**	2,658.1	2,669.2	2,369.1
Total	**$ 4,393.3**	**$ 2,533.3**	$ 2,742.6	$ 2,674.8	$ 2,483.0
Shareholders' equity					
Preferred securities	**$ 121.5**	**$ 121.5**	$ 127.5	$ 127.4	$ 121.4
Share capital	**2,278.6**	**1,756.2**	1,739.2	1,698.3	1,683.9
Retained earnings	**2,122.0**	**2,122.0**	1,992.2	1,908.5	1,811.2
Foreign currency translation adjustment	**30.3**	**30.3**	69.2	72.8	-
Total	**$ 4,552.4**	**$ 4,030.0**	$ 3,928.1	$ 3,807.0	$ 3,616.5
Debt to cash flow(3)	**2.2x**	**1.5x**	1.6x	1.4x	1.0x
Debt to book capitalization	**47.8%**	**37.4%**	40.4%	41.2%	39.6%
Debt to market capitalization	**37.4%**	**27.1%**	29.2%	34.9%	29.9%
After tax return on average common shareholders' equity(3)	**n/a**	**10.3%**	14.6%	18.7%	32.1%
After tax return on average capital employed(3)	**n/a**	**7.2%**	9.7%	12.2%	19.1%

(1) *See note 8 to the consolidated financial statements, Acquisition of Rio Alto Exploration Ltd. Pro forma cash flow is based on the Company's trailing 12-month period, adjusted for interest expense on additional debt incurred to acquire Rio Alto, and Rio Alto's six months ended June 30, 2002 cash flow, adjusted to remove Rio Alto Resources International Inc. and acquisition costs, annualized.*

(2) *Restated for change in accounting policy (see consolidated financial statements note 2).*

(3) *Based on trailing 12-month period.*

The ratios above have been calculated with the outstanding preferred securities of the Company classified as equity. If the preferred securities were classified as long-term debt, debt to cash flow for the trailing 12-month period ended June 30, 2002, would be 1.6x (March 31, 2002 – 1.7x, December 31, 2001 – 1.5x, June 30, 2001 – 1.1x). Debt to book capitalization would be 39.3% at June 30, 2002 (March 31, 2002 – 42.3%, December 31, 2001 – 43.2%, June 30, 2001 – 41.6%) had the preferred securities been classified as long-term debt, while debt to market capitalization would be 28.5%, 30.6%, 36.6% and 31.5%, respectively. On a pro forma basis at July 1, 2002, and treating the preferred securities as long-term debt, debt to cash flow for the trailing 12-month period would be 2.3x, debt to book capitalization would be 49.2% and debt to market capitalization would be 38.5%.

PRO FORMA SENSITIVITY ANALYSIS [1]

Annualized sensitivities to certain factors, which would influence the Company's financial results, are estimated as follows:

	Cash flow from operations[2] ($ millions)	Cash flow from operations[2] (per share) (basic)	Net earnings[2] ($ millions)	Net earnings[2] (per share) (basic)
Price changes				
Oil – WTI US $1.00/bbl[3]				
Excluding financial derivatives	$91	$0.68	$62	$0.47
Including financial derivatives	$78 - $88	$0.59 - $0.66	$54 - $60	$0.40 - $0.45
Natural gas – AECO Cdn $0.10/mcf[3]				
Excluding financial derivatives	$42	$0.32	$26	$0.20
Including financial derivatives	$41 - $42	$0.31 - $0.32	$25 - $26	$0.19
Volume changes				
Oil – 10,000 bbls/d	$52	$0.39	$20	$0.15
Natural gas – 10 mmcf/d	$9	$0.07	$2	$0.02
Foreign currency rate change				
$0.01 change in Cdn $ in relation to US $[3]				
Excluding financial derivatives	$55	$0.41	$34	$0.25
Including financial derivatives	$52 - $53	$0.39 - $0.40	$32 - $33	$0.24 - $0.25
Interest rate change - 1%	$33	$0.25	$20	$0.15

(1) *The sensitivities are calculated based on pro forma 2002 second quarter results.*

(2) *Attributable to common shareholders.*

(3) *For details of financial instruments in place, see consolidated financial statement note 6.*

OTHER OPERATING HIGHLIGHTS

	THREE MONTHS ENDED			SIX MONTHS ENDED	
	JUNE 30 2002	MARCH 31 2002	JUNE 30 2001[1]	JUNE 30 2002	JUNE 30 2001[1]
NETBACK ANALYSIS *($/boe, except daily production)*					
Daily production *(boe/d)*	**369,022**	363,990	362,154	**366,520**	354,809
Sales price	**$ 25.29**	$ 21.58	$ 29.54	**$ 23.46**	$ 32.61
Royalties	**3.79**	2.78	5.03	**3.29**	6.12
Production expense	**5.76**	5.73	5.72	**5.75**	5.89
Netback	**15.74**	13.07	18.79	**14.42**	20.60
Midstream contribution	**(0.30)**	(0.22)	(0.15)	**(0.26)**	(0.16)
Administration	**0.37**	0.41	0.24	**0.39**	0.25
Interest	**0.85**	0.88	1.05	**0.86**	1.16
Foreign exchange loss	**0.03**	0.07	0.06	**0.05**	0.01
Taxes other than income tax (current)	**0.35**	0.41	0.64	**0.38**	0.59
Current income tax (North Sea)	**0.07**	0.33	0.76	**0.20**	0.55
Current income tax (Offshore West Africa)	**0.03**	0.02	-	**0.03**	-
Current income tax (Large Corporations Tax)	**0.14**	0.13	0.10	**0.13**	0.11
Cash flow	**$ 14.20**	$ 11.04	$ 16.09	**$ 12.64**	$ 18.09

[1] *Restated for change in accounting policy (see consolidated financial statement notes 1 and 2).*

	SIX MONTHS ENDED JUNE 30, 2002			
	North America	North Sea	Offshore West Africa	Total
SEGMENTED NETBACK				
Oil and liquids *($/bbl, except daily production)*				
Daily production *(bbls/d)*	**155,248**	**28,283**	**5,384**	**188,915**
Sales price	**$ 24.27**	**$ 36.31**	**$ 35.71**	**$ 26.40**
Royalties	**2.88**	**1.64**	**1.37**	**2.65**
Production expense	**6.74**	**12.66**	**15.61**	**7.88**
Netback[1]	**$ 14.65**	**$ 22.01**	**$ 18.73**	**$ 15.87**
Natural gas *($/mcf, except daily production)*				
Daily production *(mmcf/d)*	**1,042**	**24**	**-**	**1,066**
Sales price	**$ 3.39**	**$ 2.92**	**$ -**	**$ 3.38**
Royalties	**0.67**	**-**	**-**	**0.66**
Production expense	**0.56**	**1.57**	**-**	**0.58**
Netback[1]	**$ 2.16**	**$ 1.35**	**$ -**	**$ 2.14**
Barrels of oil equivalent *($/boe, except daily production)*				
Daily production *(boe/d)*	**328,949**	**32,187**	**5,384**	**366,520**
Sales price	**$ 22.22**	**$ 34.06**	**$ 35.71**	**$ 23.46**
Royalties	**3.50**	**1.44**	**1.37**	**3.29**
Production expense	**4.95**	**12.27**	**15.61**	**5.75**
Netback[1]	**$ 13.77**	**$ 20.35**	**$ 18.73**	**$ 14.42**

[1] *Netbacks do not include midstream operations.*

CONSOLIDATED BALANCE SHEETS *(millions of Canadian dollars) (unaudited)*	JUNE 30 2002	DECEMBER 31 2001
ASSETS		
Current assets		
Cash	**$ 1.2**	$ 15.0
Accounts receivable and other	**570.2**	509.0
	571.4	524.0
Property, plant and equipment *(net)*	**8,597.9**	8,442.9
	$ 9,169.3	$ 8,966.9
LIABILITIES		
Current liabilities		
Accounts payable	**$ 303.3**	$ 249.5
Accrued liabilities	**381.8**	264.2
Current portion of long-term debt *(note 3)*	**15.2**	15.9
	700.3	529.6
Long-term debt *(note 3)*	**2,404.4**	2,669.2
Future site restoration	**187.3**	193.8
Future income tax	**1,847.3**	1,767.3
	5,139.3	5,159.9
SHAREHOLDERS' EQUITY		
Preferred securities *(note 2)*	**121.5**	127.4
Share capital *(note 4)*	**1,756.2**	1,698.3
Retained earnings	**2,122.0**	1,908.5
Foreign currency translation adjustment	**30.3**	72.8
	4,030.0	3,807.0
	$ 9,169.3	$ 8,966.9

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2002	**2001**	**2002**	**2001**

CONSOLIDATED STATEMENTS OF EARNINGS *(millions of Canadian dollars, except per share amounts) (unaudited)*

	THREE MONTHS ENDED JUNE 30 2002	THREE MONTHS ENDED JUNE 30 2001	SIX MONTHS ENDED JUNE 30 2002	SIX MONTHS ENDED JUNE 30 2001
Revenue *(note 7)*	**$ 862.8**	$ 981.2	**$ 1,580.3**	$ 2,111.9
Less: royalties	**(127.3)**	(165.7)	**(218.3)**	(392.9)
	735.5	815.5	**1,362.0**	1,719.0
Expenses				
Production	**196.9**	191.3	**387.8**	385.4
Depletion, depreciation and amortization	**291.2**	217.1	**525.1**	425.2
Administration	**12.3**	7.9	**25.8**	16.2
Interest	**28.6**	34.8	**57.3**	74.2
Foreign exchange (gain) loss *(note 2)*	**(63.4)**	(32.3)	**(73.4)**	5.1
	465.6	418.8	**922.6**	906.1
Earnings Before Taxes	**269.9**	396.7	**439.4**	812.9
Taxes other than income tax	**13.4**	20.3	**28.3**	38.2
Current income tax	**7.9**	28.5	**23.7**	42.2
Future income tax	**107.9**	64.5	**146.2**	219.7
Net Earnings	**140.7**	283.4	**241.2**	512.8
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.5)	**(3.0)**	(2.9)
Revaluation of preferred securities *(note 2)*	**6.0**	4.7	**5.9**	(1.5)
Net Earnings Attributable to Common Shareholders	**$ 145.2**	$ 286.6	**$ 244.1**	$ 508.4
Net Earnings per Common Share Attributable to Common Shareholders *(note 5)*				
Basic	**$ 1.18**	$ 2.37	**$ 2.00**	$ 4.18
Diluted	**$ 1.09**	$ 2.23	**$ 1.89**	$ 4.02

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS *(millions of Canadian dollars) (unaudited)*

	SIX MONTHS ENDED JUNE 30 2002	SIX MONTHS ENDED JUNE 30 2001
Balance – Beginning of Period as Previously Reported	**$ 1,979.5**	$ 1,406.0
Change in accounting policy – foreign exchange *(note 2)*	**(71.0)**	(15.4)
Balance – Beginning of Period as Restated	**1,908.5**	1,390.6
Net earnings	**241.2**	512.8
Dividend on common shares *(note 4)*	**(30.6)**	(24.3)
Dividend on preferred securities *(net of tax)*	**(3.0)**	(2.9)
Revaluation of preferred securities *(note 2)*	**5.9**	(1.5)
Purchase of common shares *(note 4)*	**-**	(63.5)
Balance – End of Period	**$ 2,122.0**	$ 1,811.2

CONSOLIDATED STATEMENTS OF CASH FLOWS *(millions of Canadian dollars) (unaudited)*

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2002	**2001**	**2002**	**2001**
Operating Activities				
Net earnings	**$ 140.7**	$ 283.4	**$ 241.2**	$ 512.8
Non-cash items				
Depletion, depreciation and amortization	**291.2**	217.1	**525.1**	425.2
Deferred petroleum revenue tax	**1.6**	(0.7)	**3.0**	0.1
Future income tax	**107.9**	64.5	**146.2**	219.7
Unrealized foreign exchange (gain) loss	**(64.4)**	(34.1)	**(76.7)**	4.2
Cash flow provided from operations	**477.0**	530.2	**838.8**	1,162.0
Net change in non-cash working capital	**45.3**	(58.3)	**(12.2)**	(26.3)
	522.3	471.9	**826.6**	1,135.7
Financing Activities				
(Repayment) increase in bank credit facilities	**(172.0)**	40.1	**(822.5)**	(83.1)
Issue of US debt securities	**-**	-	**641.5**	-
Repayment of limited recourse loan	**-**	(22.1)	**-**	(11.8)
Issue of capital stock	**17.0**	11.7	**58.9**	22.3
Purchase of common shares	**-**	(63.4)	**-**	(94.6)
Dividend on common shares	**(15.3)**	(12.2)	**(27.4)**	(12.2)
Dividend on preferred securities	**(2.5)**	(2.6)	**(5.2)**	(5.1)
Net change in non-cash working capital	**6.9**	(6.0)	**(0.2)**	(0.8)
	(165.9)	(54.5)	**(154.9)**	(185.3)
Investing Activities				
Expenditures on property, plant and equipment	**(306.6)**	(379.3)	**(821.7)**	(1,015.2)
Net proceeds on sale of property, plant and equipment	**1.8**	11.3	**58.1**	12.5
Net expenditures on property, plant and equipment	**(304.8)**	(368.0)	**(763.6)**	(1,002.7)
Net change in non-cash working capital	**(86.6)**	(48.1)	**78.1**	56.3
	(391.4)	(416.1)	**(685.5)**	(946.4)
(Decrease) Increase in Cash	**(35.0)**	1.3	**(13.8)**	4.0
Cash – Beginning of Period	**36.2**	30.7	**15.0**	28.0
Cash – End of Period	**$ 1.2**	$ 32.0	**$ 1.2**	$ 32.0
Supplemental disclosure of cash flow information				
Interest paid	**$ 21.0**	$ 38.9	**$ 47.3**	$ 73.2
Taxes paid	**$ 34.3**	$ 28.0	**$ 63.6**	$ 80.7

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS *(tabular amounts in millions of Canadian dollars)*

1. ACCOUNTING POLICIES

The consolidated financial statements of Canadian Natural Resources Limited (the "Company") include the Company and all of its subsidiaries and partnerships, and have been prepared following the same accounting policies and methods of computation as the audited consolidated financial statements of the Company as at December 31, 2001, except as described below and in note 2. The interim consolidated financial statements contain disclosures that are supplemental to the Company's annual consolidated financial statements. Certain disclosures that are normally required to be included in the notes to the annual consolidated financial statements have been condensed. These financial statements should be read in conjunction with the Company's audited consolidated financial statements and notes thereto for the year ended December 31, 2001.

Midstream Operations

As a result of the Company's increasing midstream activities, the Company determined that effective January 1, 2002, the midstream activities within North America constitute a distinct operating segment. The Company carries its midstream assets at the lower of capitalized cost and net recoverable amount. Midstream assets are depreciated over their estimated useful lives of 20 to 30 years.

Comparative Figures

Certain figures provided for prior periods have been reclassified to conform to the presentation adopted in 2002.

2. CHANGE IN ACCOUNTING POLICY

Foreign Currency Translation

Effective January 1, 2002, the Company retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. As a result of adopting this new standard, gains or losses on the translation of long-term debt denominated in US dollars are no longer deferred and amortized over the term of the debt, but are recognized in net earnings immediately. This new standard has been adopted retroactively and prior periods have been restated.

The new standard affects the Company's accounting for foreign denominated long-term debt and preferred securities. Adoption of the new accounting policy had the following effects on the Company's consolidated financial statements:

	THREE MONTHS ENDED		SIX MONTHS ENDED		YEAR ENDED
	JUNE 30 2002	**JUNE 30 2001**	**JUNE 30 2002**	**JUNE 30 2001**	**DEC 31 2001**
Decrease deferred foreign exchange loss	**$ -**	$ (17.8)	**$ -**	$ (17.8)	$ (61.9)
(Decrease) increase preferred securities	**$ (6.0)**	$ (4.7)	**$ (5.9)**	$ 1.5	$ 9.1
Decrease opening retained earnings	**$ (69.0)**	$ (58.1)	**$ (71.0)**	$ (15.4)	$ (15.4)
Increase foreign exchange (gain) loss	**$ (75.1)**	$ (32.5)	**$ (77.2)**	$ 4.0	$ 48.1
(Decrease) increase revaluation of preferred securities	**$ (6.0)**	$ (4.7)	**$ (5.9)**	$ 1.5	$ 7.4

3. LONG-TERM DEBT

		PRO FORMA JULY 1 2002[1]		JUNE 30 2002		DECEMBER 31 2001
Bank credit facilities						
Canadian dollar debt	$	1,962.4	**$**	**494.4**	$	1,003.4
US dollar debt *(Pro forma – US $170 million, 2002 – US $100 million, 2001– US $296 million)*		258.2		**151.9**		471.4
Medium-term notes		250.0		**250.0**		250.0
US debt securities *(2002 – US $800 million, 2001 – US $400 million)*		1,215.0		**1,215.0**		637.0
Senior unsecured notes *(Pro forma – US $328 million, 2002/2001 – US $203 million)*		502.0		**308.3**		323.3
		4,187.6		**2,419.6**		2,685.1
Current portion of long-term debt		(15.2)		**(15.2)**		(15.9)
	$	4,172.4	**$**	**2,404.4**	$	2,669.2

[1] *See note 8, Acquisition of Rio Alto Exploration Ltd.*

Bank credit facilities

At June 30, 2002, the Company had unsecured bank credit facilities of approximately $1,828 million comprised of a $100 million operating demand facility, a revolving credit and term loan facility of $1,500 million and a revolving credit and term loan facility of US $150 million.

In addition to the outstanding debt, *pro forma* letters of credit aggregating $36.3 million have been issued.

US debt securities

On January 23, 2002, the Company issued US $400 million of US debt securities, maturing January 15, 2032, bearing interest at 7.20%. Proceeds from the notes issued were used to repay bankers' acceptances under the Company's bank credit facilities, including the US $196 million bankers' acceptances. Subsequently, the Company entered into interest rate swap contracts that convert the fixed rate interest coupon into a floating interest rate for a portion of the term (note 6).

Acquisition of Rio Alto Exploration Ltd. ("Rio Alto")

On July 1, 2002, the Company had unsecured bank credit facilities of approximately $3,053 million. Credit facilities consist of an additional $500 million acquisition term credit facility, repayable in full on July 3, 2004 and the assumption of a $725 million revolving credit facility, which converts to a non-revolving reducing loan on December 13, 2002. One half of the commitment amount for this facility is repayable on December 13, 2003 followed by four equal quarterly reductions. Rio Alto debt assumed totalling $100 million is subject to an interest rate swap that fixes the rate at 5.08% plus a stamping fee.

Senior unsecured notes

On July 1, 2002, the Company assumed US $125 million of senior notes, maturing December 19, 2005, bearing interest at 7.69%. Through a currency swap, the interest and principal repayment amounts are locked in at 7.30% and $193.7 million, respectively.

4. SHARE CAPITAL

Issued

	JUNE 30, 2002		
	Number of shares *(thousands)*		**Amount**
Common shares			
Balance – January 1, 2002	**121,201**	**$**	**1,698.3**
Exercise of stock options	**1,769**		**56.6**
Issue of flow-through shares *(net of tax)*	**60**		**1.3**
Balance – June 30, 2002	**123,030**	**$**	**1,756.2**

In January 2002, the Company issued 60,000 flow-through common shares to a director of the Company at a price of $39.00 per common share, for total proceeds of $2.3 million. The value of the common shares was determined as the closing market price on The Toronto Stock Exchange on the day prior to the allotment of the common shares.

On July 1, 2002, the Company issued 10,008,000 common shares at an attributed value of $522.4 million as part of the consideration to acquire Rio Alto (note 8).

Normal Course Issuer Bid

On January 17, 2001, the Company announced its intention to make a Normal Course Issuer Bid through the facilities of The Toronto Stock Exchange and the New York Stock Exchange to purchase up to 6,114,726 common shares or 5% of the common shares outstanding of the Company on the date of announcement during the 12-month period beginning January 22, 2001 and ending January 21, 2002. As at January 21, 2002, the Company had purchased 2,537,800 common shares for a total cost of $113.3 million. The excess cost over book value of the shares purchased was applied to contributed surplus and retained earnings.

In January 2002, the Company renewed its Normal Course Issuer Bid, allowing the Company to purchase up to 6,060,180 shares or 5% of the Company's common shares outstanding on the date of announcement, during the 12-month period beginning January 23, 2002 and ending January 22, 2003. As at June 30, 2002, no common shares had been purchased under the renewed Normal Course Issuer Bid.

Dividend policy

On January 17, 2001, the Company announced the payment of a regular quarterly dividend of $0.10 per common share payable in January, April, July and October of each year.

In February 2002, the Board of Directors increased the Company's regular quarterly dividend to $0.125 per common share commencing with the April 1, 2002 payment.

Stock options

	JUNE 30, 2002	
	Stock options *(thousands)*	Weighted average exercise price
Outstanding – January 1, 2002	**12,051**	**$ 34.77**
Granted	**2,174**	**39.76**
Exercised	**(1,769)**	**31.96**
Forfeited	**(243)**	**37.31**
Outstanding – June 30, 2002	**12,213**	**$ 36.02**
Exercisable – June 30, 2002	**3,279**	**$ 32.43**

Stock-based compensation costs

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2002	**2001**	**2002**	**2001**
Stock-based compensation costs	**$ 6.0**	$ 4.7	**$ 11.5**	$ 8.8
Net earnings attributable to common shareholders				
As reported	**$ 145.2**	$ 286.6	**$ 244.1**	$ 508.4
Pro forma	**$ 139.2**	$ 281.9	**$ 232.6**	$ 499.6
Net earnings per common share attributable to common shareholders				
Basic				
As reported	**$ 1.18**	$ 2.37	**$ 2.00**	$ 4.18
Pro forma	**$ 1.13**	$ 2.33	**$ 1.90**	$ 4.11
Diluted				
As reported	**$ 1.09**	$ 2.23	**$ 1.89**	$ 4.02
Pro forma	**$ 1.05**	$ 2.19	**$ 1.80**	$ 3.95

The pro forma amounts shown above do not include the compensation costs associated with stock options granted prior to January 1, 2000.

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2002	**2001**	**2002**	**2001**
Fair value of options granted *(per common share)*				
Directors, officers and executives	**$ 17.41**	$ -	**$ 14.70**	$ 16.52
Other employees	**$ 13.81**	$ 15.21	**$ 11.91**	$ 13.68
Risk-free interest rate	**4.1%**	5.5%	**3.9%**	5.2%
Expected life *(years)*				
Directors, officers and executives	**5.5**	-	**5.5**	5.5
Other employees	**3.6**	3.6	**3.6**	3.6
Expected volatility	**34%**	36%	**38%**	40%
Expected dividend yield	**1.0%**	0.9%	**1.3%**	1.0%

5. NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2002	**2001**	**2002**	**2001**
Weighted average common shares outstanding *(thousands)*				
Basic	**122,910**	121,148	**122,264**	121,620
Diluted	**128,754**	127,244	**127,734**	127,534
Net earnings per common share attributable to common shareholders				
Basic	**$ 1.18**	$ 2.37	**$ 2.00**	$ 4.18
Diluted	**$ 1.09**	$ 2.23	**$ 1.89**	$ 4.02
Cash flow from operations per common share attributable to common shareholders				
Basic	**$ 3.86**	$ 4.36	**$ 6.82**	$ 9.51
Diluted	**$ 3.70**	$ 4.17	**$ 6.57**	$ 9.11

6. FINANCIAL INSTRUMENTS

The Company uses certain derivative financial instruments to manage its commodity prices, foreign currency and interest rate exposures. These financial instruments are entered into solely for hedging purposes and are not used for trading or other speculative purposes. The Company has the following financial derivatives outstanding as at the date hereof:

	Remaining Term	Volume	Average Price	Index
Oil				
Brent differential swaps				
	Jul. 2002 – Dec. 2002	20,000 bbls/d	US $1.28	Dated Brent/WTI
	Jan. 2003 – Dec. 2003	15,000 bbls/d	US $1.00	Dated Brent/WTI
Oil price collars				
	Jul. 2002 – Dec. 2002	150,500 bbls/d	US $21.97 – US $27.04	WTI
	Jan. 2003 – Jul. 2003	77,000 bbls/d	US $21.77 – US $27.34	WTI
	Jul. 2002 – Dec. 2002	3,000 bbls/d[1]	US $19.50 – US $22.33	WTI
	Jan. 2003 – Jun. 2003	3,000 bbls/d[1]	US $21.50 – US $25.50	WTI
Oil price fixed				
	Jul. 2002 – Dec. 2002	7,000 bbls/d[1]	US $22.13	WTI

[1] *Financial instruments assumed July 1, 2002 on acquisition of Rio Alto.*

	Remaining Term	Volume	Average Price	Index
Natural Gas				
Empress – NYMEX differential swaps				
	Jul. 2002 – Oct. 2006	5,500 mmbtu/d	US $0.73	Empress/NYMEX
NYMEX fixed				
	Jul. 2002 – Oct. 2006	10,000 mmbtu/d	Cdn $2.66	NYMEX
	Jul. 2002 – Oct. 2002	90,000 mmbtu/d(1)	US $2.85	NYMEX
	Nov. 2002 – Dec. 2002	30,000 mmbtu/d(1)	US $3.27	NYMEX
NYMEX collar				
	Nov. 2002 – Oct. 2003	30,000 mmbtu/d(1)	US $2.88 – US $6.12	NYMEX
Sumas fixed				
	Jul. 2002 – Oct. 2003	20,000 mmbtu/d	Cdn $2.85	Sumas
AECO collars				
	Jul. 2002 – Sep. 2002	50,000 GJ/d	Cdn $3.08 – Cdn $3.80	AECO
	Jul. 2002 – Dec. 2002	100,000 GJ/d	Cdn $4.25 – Cdn $6.03	AECO
	Nov. 2002 – Oct. 2003	40,000 GJ/d(1)	Cdn $3.50 – Cdn $5.38	AECO
	Nov. 2002 – Mar. 2003	30,000 GJ/d(1)	Cdn $4.00 – Cdn $8.43	AECO
AECO fixed				
	Jul. 2002 – Oct. 2002	5,000 GJ/d(1)	Cdn $2.71	AECO

(1) *Financial instruments assumed July 1, 2002 on acquisition of Rio Alto.*

	Remaining Term	Amount *($ millions)*	Average Exchange Rate *(US $/Cdn $)*
Foreign Currency			
Currency fixed	Jul. 2002 – Oct. 2002	US $0.4/month	1.37
Currency collars	Jul. 2002 – May 2003	US $4.2/month	1.43 – 1.53
	Jul. 2002 – Aug. 2004	US $25.0/month	1.51 – 1.59

	Remaining Term	Amount *($ millions)*	Exchange Rate	Interest Rate *(US $)*	Interest Rate *(Cdn $)*
Currency swap (1)	Jul. 2002 – Dec. 2005	US $125	1.5496	7.69%	7.30%

(1) *Financial instruments assumed July 1, 2002 on acquisition of Rio Alto.*

	Remaining Term	Amount ($ millions)	Fixed Rate	Floating Rate
Interest Rate				
Swaps – fixed to floating	Jul. 2002 – Jul. 2004	US $200	6.70%	LIBOR + 2.09%
	Jul. 2002 – Jul. 2006	US $200	6.70%	LIBOR + 1.58%
	Jul. 2002 – Jan. 2005	US $200	7.20%	LIBOR + 3.00%
	Jul. 2002 – Jan. 2007	US $200	7.20%	LIBOR + 2.23%
Swap – floating to fixed	Jul. 2002 – Mar. 2004	Cdn $100[1]	5.08%	

[1] *Financial instruments assumed July 1, 2002 on acquisition of Rio Alto.*

7. SEGMENTED INFORMATION

	THREE MONTHS ENDED JUNE 30		SIX MONTHS ENDED JUNE 30	
	2002	**2001**	**2002**	**2001**
Revenue				
North America	**$ 737.3**	$ 792.6	**$ 1,323.1**	$ 1,804.7
North Sea	**95.0**	165.6	**198.5**	266.1
Offshore West Africa	**17.0**	15.3	**34.8**	23.6
Midstream	**13.5**	7.7	**23.9**	17.5
	$ 862.8	$ 981.2	**$ 1,580.3**	$ 2,111.9
Net Earnings				
North America	**$ 202.2**	$ 215.4	**$ 274.9**	$ 428.7
North Sea	**(40.1)**	61.1	**(20.0)**	79.3
Offshore West Africa	**(26.1)**	4.6	**(21.5)**	(0.2)
Midstream	**4.7**	2.3	**7.8**	5.0
	140.7	283.4	**241.2**	512.8
Dividend on preferred securities *(net of tax)*	**(1.5)**	(1.5)	**(3.0)**	(2.9)
Revaluation of preferred securities	**6.0**	4.7	**5.9**	(1.5)
Net Earnings Attributable to Common Shareholders	**$ 145.2**	$ 286.6	**$ 244.1**	$ 508.4
Additions to Property, Plant and Equipment				
North America	**$ 232.5**	$ 248.6	**$ 652.6**	$ 878.9
North Sea	**10.4**	16.5	**(44.2)**	31.3
Offshore West Africa	**53.9**	96.1	**114.4**	137.9
Midstream	**5.2**	6.8	**14.8**	40.7
	$ 302.0	$ 368.0	**$ 737.6**	$ 1,088.8

Property, plant and equipment and future income taxes payable have been decreased by $26.0 million (2001 increased by $86.1 million) to provide for the tax effect of the sale and acquisition of assets in the North Sea and North America with a tax basis that differs from the purchase and sale price.

8. ACQUISITION OF RIO ALTO EXPLORATION LTD.

Effective July 1, 2002, the Company paid cash of $850.0 million and issued 10,008,000 common shares with an attributed value of $522.4 million to acquire all of the issued and outstanding common shares of Rio Alto by way of a plan of arrangement (the “Plan of Arrangement”). Rio Alto was engaged in the exploration for and production of oil and natural gas in Western Canada and South America. Under the Plan of Arrangement, Rio Alto’s South American properties were sold to a new company, Rio Alto Resources International Inc. (“Rio Alto International”), and each shareholder of Rio Alto received one share of Rio Alto International.

The acquisition of Rio Alto has strengthened the Company’s exposure to natural gas production in Western Canada and will provide additional cash flow to fund future capital projects.

The acquisition will be accounted for based on the purchase method. Results from Rio Alto will be consolidated with the results of the Company effective July 1, 2002. The preliminary estimate of the allocation of the purchase price to assets acquired and liabilities assumed based on their fair values is set out in the following table:

		JULY 1 2002
Purchase price:		
Share consideration	$	522.4
Cash consideration		850.0
Total consideration		1,372.4
Long-term debt assumed		937.1
Total purchase price	$	2,309.5
Net assets acquired:		
Property, plant and equipment	$	3,237.3
Future income tax		(845.0)
Future site restoration		(1.8)
Working capital		(81.0)
Total net assets acquired	$	2,309.5

The purchase price allocation is based on preliminary estimates of the fair values of the assets acquired, the liabilities assumed and the costs to complete the acquisition. The preliminary allocation is subject to change as actual amounts are determined.

INTEREST COVERAGE RATIOS

The following financial ratios are provided in connection with the Company's continuous offering of medium-term notes pursuant to the short form prospectus dated July 24, 2001. These ratios are based on the Company's consolidated financial statements that are prepared in accordance with accounting principles generally accepted in Canada.

Interest coverage ratios for the 12-month period ended June 30, 2002:	
Interest coverage *(times)*	
Net earnings	6.4[(1)]
Cash flow	14.8[(2)]

[(1)] *Net earnings plus income taxes and interest expense; divided by interest expense.*

[(2)] *Cash flow plus current income taxes and interest expense; divided by interest expense.*

The interest coverage ratios have been calculated without including the annual carrying charges relating to the outstanding preferred securities of the Company. If the preferred securities were classified as long-term debt, these annual carrying charges would be included in interest. If these annual carrying charges had been included in the calculations, the net earnings coverage ratio for the 12-month period ended June 30, 2002, would be 5.9x and the cash flow coverage ratio for the 12-month period ended June 30, 2002 would be 13.6x.

SUPPLEMENTARY INFORMATION (UNAUDITED) RELATED TO THE ACQUISITION OF RIO ALTO EXPLORATION LTD. EFFECTIVE JULY 1, 2002

	JUNE 30, 2002			
	Canadian Natural Resources Limited	Rio Alto Exploration Ltd.	Pro forma Adjustments *(note B)*	Pro forma Consolidated
***PRO FORMA* CONSOLIDATED BALANCE SHEET** *(millions of Canadian dollars) (unaudited)*				
ASSETS				
Current assets				
Cash	$ 1.2	$ 10.1	$ (3.6)	$ 7.7
Accounts receivable and other	570.2	126.4	(1.8)	694.8
	571.4	136.5	(5.4)	702.5
Property, plant and equipment *(net)*	8,597.9	2,399.8	837.5	11,835.2
	$ 9,169.3	$ 2,536.3	$ 832.1	$ 12,537.7
LIABILITIES				
Current liabilities				
Accounts payable	$ 303.3	$ 143.4	$ (22.0)	$ 424.7
Accrued liabilities	381.8	-	90.7	472.5
Current portion of long-term debt	15.2	117.1	(117.1)	15.2
Current portion of obligations under capital leases	-	11.0	-	11.0
	700.3	271.5	(48.4)	923.4
Long-term debt	2,404.4	800.9	967.1	4,172.4
Obligations under capital leases	-	8.1	-	8.1
Future site restoration	187.3	4.5	(2.7)	189.1
Future income tax	1,847.3	524.8	320.2	2,692.3
	5,139.3	1,609.8	1,236.2	7,985.3
SHAREHOLDERS' EQUITY				
Preferred securities	121.5	-	-	121.5
Share capital	1,756.2	482.2	40.2	2,278.6
Retained earnings	2,122.0	444.3	(444.3)	2,122.0
Foreign currency translation adjustment	30.3	-	-	30.3
	4,030.0	926.5	(404.1)	4,552.4
	$ 9,169.3	$ 2,536.3	$ 832.1	$ 12,537.7

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS (LOSS) *(millions of Canadian dollars) (unaudited)*

SIX MONTHS ENDED JUNE 30, 2002	Canadian Natural Resources Limited	Rio Alto Exploration Ltd.	Pro forma Adjustments *(note B)*	Pro forma Consolidated
Revenue	$ 1,580.3	$ 363.3	$ (37.4)	$ 1,906.2
Less: royalties	(218.3)	(91.3)	14.1	(295.5)
	1,362.0	272.0	(23.3)	1,610.7
Expenses				
Production	387.8	57.6	(7.6)	437.8
Depletion, depreciation and amortization	525.1	176.6	44.3	746.0
Administration	25.8	35.5	(21.6)	39.7
Interest	57.3	20.6	20.3	98.2
Foreign exchange (gain) loss	(73.4)	0.2	(4.7)	(77.9)
	922.6	290.5	30.7	1,243.8
Earnings (Loss) Before Taxes	439.4	(18.5)	(54.0)	366.9
Taxes other than income tax	28.3	-	-	28.3
Current income tax	23.7	(5.1)	-	18.6
Future income tax (recovery)	146.2	(1.3)	(24.6)	120.3
Net Earnings (Loss)	241.2	(12.1)	(29.4)	199.7
Dividend on preferred securities *(net of tax)*	(3.0)	-	-	(3.0)
Revaluation of preferred securities	5.9	-	-	5.9
Net Earnings Attributable to Common Shareholders	$ 244.1	$ (12.1)	$ (29.4)	$ 202.6

PRO FORMA CONSOLIDATED STATEMENT OF CASH FLOW FROM OPERATIONS
(millions of Canadian dollars) (unaudited)

SIX MONTHS ENDED JUNE 30, 2002	Canadian Natural Resources Limited	Rio Alto Exploration Ltd.	Pro forma Adjustments *(note B)*	Pro forma Consolidated
Operating Activities				
Net earnings (loss)	$ 241.2	$ (12.1)	$ (29.4)	$ 199.7
Non-cash items				
Depletion, depreciation and amortization	525.1	176.6	44.3	746.0
Deferred petroleum revenue tax	3.0	-	-	3.0
Future income tax (recovery)	146.2	(1.3)	(24.6)	120.3
Unrealized foreign exchange (gain) loss	(76.7)	0.2	(4.7)	(81.2)
Cash flow provided from operations	838.8	163.4	(14.4)	987.8
Net change in non-cash working capital	(12.2)	48.8	120.4	157.0
	$ 826.6	$ 212.2	$ 106.0	$ 1,144.8

PRO FORMA CONSOLIDATED STATEMENT OF EARNINGS *(millions of Canadian dollars) (unaudited)*

	YEAR ENDED DECEMBER 31, 2001			
	Canadian Natural Resources Limited *(note B)*	**Rio Alto Exploration Ltd.** *(note B)*	**Pro forma Adjustments** *(note B)*	**Pro forma Consolidated**
Revenue	$ 3,588.8	$ 1,188.5	$ (25.6)	$ 4,751.7
Less: royalties	(580.3)	(297.9)	4.3	(873.9)
	3,008.5	890.6	(21.3)	3,877.8
Expenses				
Production	757.9	104.7	(8.1)	854.5
Depletion, depreciation and amortization	903.8	526.2	(111.7)	1,318.3
Administration	37.6	30.5	(5.2)	62.9
Interest	137.8	55.1	36.9	229.8
Foreign exchange loss	62.8	4.0	-	66.8
Loss on sale of United States assets	24.1	-	-	24.1
	1,924.0	720.5	(88.1)	2,556.4
Earnings Before Taxes	1,084.5	170.1	66.8	1,321.4
Taxes other than income tax	69.1	-	-	69.1
Current income tax	76.9	10.0	-	86.9
Future income tax	282.5	82.7	11.2	376.4
Net Earnings	656.0	77.4	55.6	789.0
Dividend on preferred securities *(net of tax)*	(5.9)	-	-	(5.9)
Revaluation of preferred securities	(7.5)	-	-	(7.5)
Net Earnings Attributable to Common Shareholders	$ 642.6	$ 77.4	$ 55.6	$ 775.6

***PRO FORMA* CONSOLIDATED STATEMENT OF CASH FLOW FROM OPERATIONS**
(millions of Canadian dollars) (unaudited)

YEAR ENDED DECEMBER 31, 2001	Canadian Natural Resources Limited *(note B)*	Rio Alto Exploration Ltd. *(note B)*	Pro forma Adjustments *(note B)*	Pro forma Consolidated
Operating Activities				
Net earnings	$ 656.0	$ 77.4	$ 55.6	$ 789.0
Non-cash items				
Depletion, depreciation and amortization	903.8	526.2	(111.7)	1,318.3
Loss on sale of United States assets	24.1	-	-	24.1
Deferred petroleum revenue tax	(0.2)	-	-	(0.2)
Future income tax	282.5	82.7	11.2	376.4
Unrealized foreign exchange loss	64.1	4.0	-	68.1
Cash flow provided from operations	1,930.3	690.3	(44.9)	2,575.7
Net change in non-cash working capital	(42.2)	17.2	156.3	131.3
	$ 1,888.1	$ 707.5	$ 111.4	$ 2,707.0

NOTES TO THE *PRO FORMA* CONSOLIDATED FINANCIAL STATEMENTS

(tabular amounts in millions of Canadian dollars) (unaudited)

A. BASIS OF PRESENTATION

These *pro forma* consolidated financial statements have been prepared for information purposes by management in accordance with generally accepted accounting principles in Canada. These *pro forma* consolidated financial statements were prepared on a basis consistent with the *pro forma* consolidated financial statements included in the Information Circular of Rio Alto Exploration Ltd. ("Rio Alto") in connection with the annual and special meeting of the securityholders of Rio Alto to approve the plan of arrangement (the "Plan of Arrangement") involving Rio Alto, its securityholders, Canadian Natural Resources Limited ("Canadian Natural") and Rio Alto Resources International Inc. ("Rio Alto International").

The *pro forma* consolidated financial statements have been prepared from:

- the unaudited interim consolidated financial statements of Canadian Natural and Rio Alto as at and for the six months ended June 30, 2002; and

- the audited consolidated financial statements of Canadian Natural and Rio Alto as at and for the year ended December 31, 2001.

The *pro forma* consolidated balance sheet gives effect to the transaction as if it occurred on the balance sheet date while the *pro forma* consolidated statements of earnings and cash flow from operations give effect to the transaction as if it had occurred at the beginning of the period.

The *pro forma* consolidated financial statements are not necessarily indicative of results of operations that would have occurred if the events reflected therein had been in effect on the dates indicated or of the results of operations that may be obtained in the future. In preparing these *pro forma* consolidated financial statements, no adjustments have been made to reflect the operating synergies, general and administrative cost savings or tax benefits expected to result from the combination of Canadian Natural and Rio Alto. The purchase price allocation is based on estimates and the actual allocation could vary from this estimate.

The *pro forma* consolidated financial statements should be read in conjunction with the unaudited interim consolidated financial statements of Canadian Natural for the six months ended June 30, 2002 and the audited consolidated financial statements of Canadian Natural and Rio Alto for the year ended December 31, 2001.

B. *PRO FORMA* ADJUSTMENTS AND ASSUMPTIONS

The *pro forma* consolidated financial statements include the following adjustments and assumptions:

- The purchase of all of the common shares outstanding of Rio Alto for aggregate consideration of $1,372.4 million comprised of $850.0 million in cash and 10,008,000 common shares of Canadian Natural with an attributed value of $522.4 million. Expenditures to settle the stock options outstanding of Rio Alto were $16.5 million. Interest expense at 5.0% has been assumed on the net cash portion of the purchase transaction and transaction costs, including integration and redundancy costs, are estimated to be $20.0 million. Working capital has been adjusted to record a liability of $42.0 million for the negative mark-to-market value of physical and financial commodity price contracts. The acquisition is accounted for based on the purchase method as follows:

		JUNE 30 2002
Purchase price:		
Share consideration	**$**	**522.4**
Cash consideration		**850.0**
Total consideration		**1,372.4**
Long-term debt assumed		**937.1**
Total purchase price	**$**	**2,309.5**
Net assets acquired:		
Property, plant and equipment	**$**	**3,237.3**
Future income tax		**(845.0)**
Future site restoration		**(1.8)**
Working capital		**(81.0)**
Total net assets acquired	**$**	**2,309.5**

The purchase price allocation is based on preliminary estimates of the fair values of the assets acquired, the liabilities assumed and the costs to complete the acquisition. The preliminary allocation is subject to change as actual amounts are determined.

- Effective January 1, 2002, Canadian Natural and Rio Alto retroactively adopted the Canadian Institute of Chartered Accountants' new accounting standard with respect to foreign currency translation. The consolidated financial statements of Canadian Natural and Rio Alto as at and for the year ended December 31, 2001, have been restated to reflect the adoption of the new standard.

- The *pro forma* consolidated financial statements reflect only the North American operations of Rio Alto. Under the Plan of Arrangement, the South American operations of Rio Alto were acquired by a new public company, Rio Alto International. Revenues, royalties, production expense, depletion depreciation and amortization, administration expense, interest expense, foreign exchange (gain) loss, future income tax expense, accounts receivable and other, property plant and equipment, accrued liabilities and future site restoration have been adjusted to reflect this transaction.

- The current portion of Rio Alto's long-term debt has been reclassified to long-term debt to reflect the re-negotiation of certain Rio Alto debt agreements.

- Royalties have been adjusted to reflect that the Alberta Royalty Tax Credit would have been lower by approximately $0.5 million for the year ended December 31, 2001 ($0.3 million for the six months ended June 30, 2002) as if Canadian Natural and Rio Alto had been associated throughout the period.

- Depletion, depreciation and amortization has been adjusted to reflect the *pro forma* value of the property, plant and equipment at the assumed acquisition date.

- Depletion, depreciation and amortization expense for the year ended December 31, 2001, has been reduced by $210.4 million as the ceiling test deficiency on Rio Alto's Canadian properties has been offset by the ceiling test cushion on Canadian Natural's Canadian properties.

- Administration expense for the six months ended June 30, 2002 has been reduced by $20.9 million to reflect one time transaction costs that were incurred in Rio Alto as a result of the acquisition by Canadian Natural.

- Interest expense has been adjusted to reflect the additional debt incurred as a result of the acquisition.
- Future income tax expense has been adjusted for the impact of the above items that affect current period earnings.

C. NET EARNINGS AND CASH FLOW FROM OPERATIONS PER COMMON SHARE

Pro forma net earnings per common share attributable to common shareholders and *pro forma* cash flow from operations per common share attributable to common shareholders have been calculated using the weighted average number of Canadian Natural common shares outstanding during the periods plus the additional common shares of Canadian Natural to be issued as part of the acquisition as if the additional common shares were outstanding throughout the period.

	SIX MONTHS ENDED JUNE 30, 2002		
	Canadian Natural Resources Limited	**Pro forma Adjustments**	**Pro forma Consolidated**
Common shares, issued and outstanding *(thousands)*	**123,030**	**10,008**	**133,038**
Weighted average common shares outstanding *(thousands)*			
Basic	**122,264**	**10,008**	**132,272**
Diluted	**127,734**	**10,008**	**137,742**
Net earnings per common share attributable to common shareholders			
Basic	**$ 2.00**		**$ 1.53**
Diluted	**$ 1.89**		**$ 1.45**
Cash flow from operations per common share attributable to common shareholders			
Basic	**$ 6.82**		**$ 7.43**
Diluted	**$ 6.57**		**$ 7.17**

	YEAR ENDED DECEMBER 31, 2001		
	Canadian Natural Resources Limited	**Pro forma Adjustments**	**Pro forma Consolidated**
Common shares, issued and outstanding *(thousands)*	121,201	10,008	131,209
Weighted average common shares outstanding *(thousands)*			
Basic	121,300	10,008	131,308
Diluted	126,777	10,008	136,785
Net earnings per common share attributable to common shareholders			
Basic	$ 5.30		$ 5.91
Diluted	$ 5.09		$ 5.77
Cash flow from operations per common share attributable to common shareholders			
Basic	$ 15.82		$ 19.54
Diluted	$ 15.39		$ 18.83

2002 THIRD QUARTER RESULTS

2002 third quarter results are scheduled for release Wednesday, November 6, 2002. A conference call will be held at 9:00 a.m. Mountain Standard Time, 11:00 a.m. Eastern Standard Time.

CORPORATE PROFILE

Canadian Natural Resources Limited is a senior independent oil and natural gas exploration, development and production company based in Calgary, Alberta. The Company's operations are focused in Western Canada, the North Sea and Offshore West Africa.

Canadian Natural's profitable growth has been based on the fundamental principles of effective cost control, manageable bank debt and a defined operating strategy. The strategy follows a balanced approach to exploration and acquisitions, combined with a focus on cost effective exploitation in defined core areas. Adhering to this strategy has resulted in Canadian Natural building a strong asset base that is diversified among commodities produced, namely natural gas, light and Pelican Lake oil, primary heavy oil and thermal heavy oil.

CORPORATE INFORMATION

Management Committee

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Chairman

John G. Langille
President

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Executive Vice-President, Exploration

Steve W. Laut
Executive Vice-President, Operations

Allen M. Knight
Senior Vice-President, International and Corporate Development

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Senior Vice-President, North American Operations

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Vice-President, Marketing

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Keith A.J. MacPhail

Allan P. Markin

James S. Palmer, C.M., Q.C.

Eldon R. Smith, M.D.

David A. Tuer

Stock Listing

The Toronto Stock Exchange
Symbol: CNQ
New York Stock Exchange
Symbol: CED

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Trading Symbols
The Toronto Stock Exchange – CNQ   New York Stock Exchange – CED

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